

**CALIFORNIA ENERGY COMMISSION**

1516 NINTH STREET

SACRAMENTO, CA 95814-5512

DATE: August 19, 2004

TO: Interested Parties

FROM: Donna Stone, Compliance Project Manager

SUBJECT: **Mountainview Power Project (00-AFC-2C)  
Staff Analysis of Proposed Modifications to Conditions  
of Certification Air Quality-1, -2, -3, -4, -5, -6, -9, -10, -11, -12, 15, -16, -  
18, -23, -24, -25, -28, -36 and -38; Deletion of Condition Air Quality-13,  
and Reinstatement of Condition Air Quality-19.**

On March 1, 2004, the California Energy Commission received a request from Mountainview Power Company, LLC, to amend the Energy Commission Decision for the Mountainview Power Project.

The Mountainview Power Project is a nominal 1,056 MW natural gas-fired power plant that was certified by the Energy Commission on March 21, 2001, and restarted construction on March 15, 2004, after a long construction hiatus. The facility is located in San Bernardino County at the intersection of San Bernardino and Mountainview Avenues in the City of Redlands, within the boundaries of the South Coast Air Quality Management District (District).

The proposed modifications reflect final engineering design and incorporate District air permit modifications. These modifications will allow the project owner to:

- Change the Emergency Fire Pump from the originally approved Cummins 182 bhp fire water pump to the, District requested, Clarke 375 bhp engine that emits at lower g/hp emission levels.
- Have all four turbines in start-up mode simultaneously, if need be.
- Incorporate recent improved data into the permit conditions to allow for more flexibility during turbine commissioning and tuning periods.

Energy Commission staff have determined that minor changes in the District permit necessitate some minor changes to the Energy Commission Air Quality Conditions of Certification: AQ-3, -4, -5, -9, -12, -15, -16, -18, -23, -24, -28, and -38. AQ-13 will need to be deleted because it was based on an outdated assumption made by the applicant, and is no longer needed. Additionally, Energy Commission staff reviewed the proposed petition and assessed the impacts of this proposal on environmental quality, public health and safety. Staff proposes revisions to existing conditions of certification for Air Quality -2 and -36, and the reinstatement of AQ-19.

August 18, 2004

Page 2

With the modifications to the Conditions of Certification identified above, Energy Commission staff have determined that the project will remain in compliance with applicable laws, ordinances, regulations, and standards and that the proposed modifications will not result in a significant adverse direct or cumulative impact to the environment (Title 20, California Code of Regulations, Section 1769).

The amendment petition has been posted on the Energy Commission's webpage at [www.energy.ca.gov/sitingcases](http://www.energy.ca.gov/sitingcases). Staff's analysis is attached for your information and review. Staff's analysis and the order (if the amendment is approved) will also be posted on the webpage. Energy Commission staff intends to recommend approval of the petition at the September 8, 2004 Business Meeting of the Energy Commission. If you have comments on this proposed project change, please submit them to me at the address above prior to September 8, 2004. If you have any questions, please call me at (916) 654-4745 or e-mail at [dstone@energy.state.ca.us](mailto:dstone@energy.state.ca.us).

Attachment

**Mountainview Power Plant Project (00-AFC-2C)**  
**Request to Amend the Air Quality Conditions of Certification**  
**Prepared by: Joseph M. Loyer**  
**August 18, 2004**

**Amendment Request**

The Mountainview Power Company, LLC (MVPC) filed a petition on February 16, 2004 with the California Energy Commission (Energy Commission) for modifications to the Air Quality Conditions of Certification of the Mountainview Power Plant Project (Mountainview), located within the South Coast Air Quality Management District (District) in order to complete construction and become operational.

MVPC has petitioned the District and Energy Commission to make changes to the Conditions of Certification in three distinct areas. MVPC is petitioning to: (1) extend the time allotted for commissioning activities from 33 days to 636 hours for each turbine, (2) add the definition of a "cold startup" and increase the allowable NO<sub>x</sub> emissions during all startups, (3) add the definition of and emission constraints for "combustor tuning," and (4) change the firewater pump to a newer and larger engine. The MVPC petition will require the Energy Commission to modify a paragraph describing the firewater pump and the Conditions of Certification AQ-1, -6, -10, -25 and -36.

The MVPC petition to the District for these NO<sub>x</sub> emission increases has triggered a BACT adjustment for NO<sub>x</sub> via the District Rules and Regulations (discussed below in the LORS section) from 2.5 ppm @ 15% O<sub>2</sub> to 2.0 ppm @ 15% O<sub>2</sub>. The new BACT finding must be incorporated into Conditions of Certification AQ-11 and -36.

In a previous petition to the Energy Commission, MVPC (at that time owned by a different company) requested that the 5,900 brake horsepower (bhp) Black-Start engine be replaced with a smaller engine (2,200 bhp) and inducted into a District program enabling the deletion of Condition of Certification AQ-19. However, this petition was not acted upon by the District, and thus while this change was made by the Energy Commission, it was never completed by the District. At this time, MVPC does not intend to install either a 5,900 bhp or a 2,200 bhp Black-Start engine, but have not determined what Black-Start engine they will install. Therefore, MVPC has requested that the Conditions of Certification reflect the original 5,900 Bhp Black-Start engine as currently described in the District permit so that the Energy Commission and District match. This will require Condition of Certification AQ-19 be reinstated, a minor modification to AQ-36, and minor modifications to the equipment description paragraph for the Black-Start engine.

To better reflect the District permit conditions, Staff is proposing to change Condition of Certification AQ-2 to require the use of a formula to track ammonia emissions that has been imposed by the District.

Additionally, staff is aware of several changes in the District permit that, although minor in nature, need to be reflected in the Energy Commission Conditions of Certification.

The Conditions that need these minor modifications are AQ-3, -4, -5, -9, -12, -15, -16, -18, -23, -24, -28 and -38. Additionally, AQ-13 will need to be deleted.

### **Background**

MVPC was granted a license by the Energy Commission on March 21, 2001 to construct and operate a 1,056 MW combined cycle power plant with four GE Frame 7FA combustion turbines, each equipped with heat recovery steam generators (HRSG) which provide steam for two steam turbines. Emissions are to be controlled by a combination of dry-low NO<sub>x</sub> combustors (DLN), selective catalytic reduction (SCR), and oxidation catalysis. The project is located in San Bernardino County within the property boundary of an existing decommissioned twin boiler power plant.

On September 10, 2001, the Energy Commission granted MVPC a petition that included the separation of the exhaust stacks from two twin stacks to four separate stacks, changes to the site configuration, changes to the cooling towers, changes to the design ambient temperature, a smaller emergency engine and increases in the NO<sub>x</sub> startup emission limits. On January 9, 2002 the Energy Commission granted MVPC a petition that deleted Condition AQ-19 (the emergency engine emission controls) in favor of an engine registration program whose requirements instituted more rigorous controls. However, the District permit to construct (PTC) was never amended for either of these modifications.

MVPC has now petitioned the District to amend their PTC with not only this petition currently before the Energy Commission, but also the September 10, 2001 petition already granted by the Energy Commission. Therefore, the NO<sub>x</sub> emission increases associated with the change in startup emission limits trigger a Best Available Control Technology (BACT) assessment for NO<sub>x</sub> to be performed by the District.

### **Laws Ordinances Regulations and Standards**

District Rule 2005(c)(1)(A) states that existing RECLAIM facilities (such as Mountainview) that increase their annual allocation to a level greater than their starting allocation must either apply current BACT standards or, demonstrate that the emission increase will not result in a significant increase in ambient air quality impacts. The proposed emission increases in both the initial commissioning and startup limits will result in a substantial increase in Mountainview's first year NO<sub>x</sub> allocation. Thus, MVPC has chosen to accept the revised BACT finding for NO<sub>x</sub> by the District which is 2.0 ppmv @ 15% O<sub>2</sub> averaged over one hour. In addition to the District BACT finding for NO<sub>x</sub> the District has also indicated that the first year allocation will have to be recalculated with the new emission assumptions. Based on the District calculations, the first year Reclaim Trade Credits (RTCs) allocation for Mountainview is 492,897 lbs.

The District has also included exceptions language in MVPC's permit for defined instances where MVPC may emit beyond the NO<sub>x</sub> emission limit specified in their revised BACT determination. The allowable exceptions are defined in AIR QUALITY Table 2; this language is similar to exception language found in the Inland Empire Energy Center project and was originally developed by Energy Commission staff. These exceptions are limited to no more than 15 occurrences per year for each turbine,

two hours in duration, and 25 ppm @ 15% O<sub>2</sub> averaged over an hour in concentration for each occurrence. While it is clear that 15 such events within a year would not jeopardize the annual emission limit, it is not clear that an emission of 25 ppm would not cause a violation of the 1-hour NO<sub>2</sub> California Ambient Air Quality Standard (1-hr NO<sub>2</sub> CAAQS). Therefore, MVPC has submitted air dispersion modeling results to reflect the 25 ppm NO<sub>x</sub> emission and has determined that the maximum project impact under such conditions is 418 ug/m<sup>3</sup> (includes all four turbines in exception, ozone limiting and a background ambient air quality of 261 ug/m<sup>3</sup>). This potential impact is approximately 89% of the 1-hr NO<sub>2</sub> CAAQS. Staff has reviewed this air dispersion modeling and has found that MVPC NO<sub>x</sub> emissions will not result in an exceedance of the 1-hr NO<sub>2</sub> CAAQS. Therefore, staff is confident that neither a federal nor a California ambient air quality standard will be violated as a result of the ultimate NO<sub>x</sub> emission limit in the exception language.

**AIR QUALITY Table 1**  
**Permitted Exception to the NO<sub>x</sub> limit –**  
**Limited to 15 1-hour occurrences total per year per turbine**

<b>A.</b>	<b>Qualifying operating conditions under which an exception may be granted:</b>
a)	Rapid turbine load changes under the following conditions:
*	Load changes initiated by the California ISO when the plant is operating under Automatic General Control.
*	Activation of plant automatic safety or equipment protection systems which rapidly decrease turbine load.
b)	The first two 1-hour reporting periods following the initiation/shutdown of the evaporative cooler supply pump.
c)	The first two 1-hour reporting periods following the initiation of HRSG duct burners.
d)	Events as a result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or their designees.
<b>B.</b>	The 1-hour average NO <sub>x</sub> emissions above 2.0 ppm, dry basis at 15% O <sub>2</sub> , did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).
<b>C.</b>	The qualified operating conditions under ( <b>A.</b> ) above are recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating conditions. The notations in the log and CEMS must describe the data and time of entry into the log/CEMS and the plant operating conditions responsible for NO <sub>x</sub> emissions exceeding the 2.0 ppmv @ 15% O <sub>2</sub> 1-hour average limit.
<b>D.</b>	The 1-hour average NO <sub>x</sub> concentration for the period that results from a qualified operating condition does not exceed 25 ppmv, dry basis at 15% O <sub>2</sub> .
<b>NOTE:</b>	All NO <sub>x</sub> emissions during these events shall be included in all calculations of hourly, daily and annual mass emission rates as required by this permit.

### Analysis

In order to provide a more streamlined discussion of the petitioned project changes, the resulting emissions and associated mitigation, staff has provided a summary analysis below with the bulk of the analysis in Appendix A. Staff has also provided a condition by condition explanation of each proposed modification in Appendix B.

**Initial Commissioning**

Initial commissioning is the process by which the power plant facility goes from construction phase into operation phase. This is the time when the turbines first fire fuel and critical systems are tested, potentially modified and re-tested, and started to full speed and load for the first time. Depending on the complexity and construction of the power plant and all the related sub-systems, the initial commissioning period can be as short as 12 days or as long as 90 days. General Electric has recently recommended that the Frame 7FA turbine be allotted 636 hours of initial commissioning time (which is approximately 80 8-hour days). After a discussion with the District, Energy Commission staff is inclined to agree with General Electric's recommendation. MVPC has been granted a new initial NOx RTC allocation with which to perform initial commissioning and subsequent operation within the first year.

**Startups and Shutdowns**

Recent information regarding startups and shutdowns at large combined cycle power plants indicate that after an extended shutdown (three days or more), the HRSGs and steam turbines are too cold to start quickly (i.e., approximately within 3 hours). Indications are that, from a cold state, each combustion turbine may require up to 6 hours to start, primarily constrained by the need to slowly warm up the HRSGs. MVPC has requested that they be allowed enough time to perform at least one cold startup per turbine per year. Longer startup times typically have the potential for a short-term emission impact. However, Mountainview has only monthly emission limits, and thus staff is confident that MVPC is unlikely to exceed those limits. The monthly emission limits were established and offset by MVPC in the original licensing case. Therefore, if those emission limits are not violated, staff can find no unmitigated impacts that would require further offsets. As stated above, MVPC has been granted a new initial NOx RTC allocation, which also includes the startup and shutdown emissions.

**Periodic Combustor Tuning**

In some cases, GE Frame 7FA combustion turbines have experienced periodic failures of certain components in their DLN combustors. Such failure requires the combustor component to be replaced and the turbine re-tuned. This re-tuning may produce higher emissions than under normal operating conditions. Thus, while re-tuning, it is unlikely that the turbine will be able to comply with the normal operating emission constraints. MVPC proposes to treat this re-tuning period similar to a cold startup, proposing that it take no longer than 6 hours to perform. As stated above, MVPC has been granted a new initial NOx RTC allocation, which also accounts for the combustor tuning emissions.

**Black Start Engine & Diesel Powered Firewater Pump**

In a previous amendment, MVPC petitioned the Energy Commission to approve a smaller diesel powered black-start engine for Mountainview. The original black-start engine was 5,900 bhp in size and had significant emissions that were fully mitigated. The smaller black-start engine was proposed to be 2,200 bhp, would have been newer and have lower emission rates. However, MVPC has determined that they are uncertain as to the eventual size of the black-start engine. Since the modification the black-start engine was never completed in the District permits, MVPC is requesting that

the Energy Commission Conditions of Certification retain the original size and emission profile of the 5,900 bhp black-start engine. This will require that Condition AQ-19 be reinstated and that the equipment description paragraph within the Conditions of Certification be revised. Additionally, the NO<sub>x</sub> RTC requirements will need to reflect the NO<sub>x</sub> emission from the required periodic testing of the 5,900 black-start engine. As stated above, MVPC has been granted a new initial NO<sub>x</sub> RTC allocation, which also accounts for the black-start engine emissions.

MVPC is proposing to substitute a Clarke 375 bhp diesel engine to serve as the firewater pump for the Cummins 182 bhp diesel engine for which they were originally licensed. Although the engine size is significantly larger, the engine is newer and must comply with more stringent emission limitations set by the California Air Resources Board (CARB). However, the expected emissions of NO<sub>x</sub> and SO<sub>x</sub> from periodic testing will increase, although PM<sub>10</sub>, CO and VOC emissions will decrease. The NO<sub>x</sub> and SO<sub>x</sub> emissions (4.2 lbs/hr and 0.116 lbs/hr respectively) do not represent a significant amount. Therefore, staff is confident that the Mountainview project can operate well within the annual RECLAIM limits for NO<sub>x</sub> and its monthly emission limits for SO<sub>x</sub> and.

#### **Replacement of Condition of Certification AQ-2**

Staff is recommending that Condition of Certification AQ-2 be replaced. Condition AQ-2 was originally instituted to ensure that Mountainview's annual NO<sub>x</sub> emissions did not exceed its permit limits. This was of concern because MVPC made the assumption that, on an hourly basis, the project NO<sub>x</sub> emissions could be as high as 2.5 ppm at 15% O<sub>2</sub>, while the annual emissions were based on an assumption that project NO<sub>x</sub> emissions would not exceed 2.0 ppm at 15% O<sub>2</sub>. To ensure that the Mountainview project emissions did not exceed the annual assumption, the District imposed a fuel limit and a total mass emissions limit. However, because the hourly and annual emission limits are now both 2.0 ppm at 15% O<sub>2</sub>, the District is proposing to delete the limit of AQ-2 in favor of the RECLAIM limits placed in Conditions AQ-36. Staff agrees with this decision, as these two conditions would be redundant.

Staff proposes to replace Condition AQ-2 with two required ammonia slip compliance formulae. Ammonia slip is the result of unreacted ammonia passing through the SCR system, which is the NO<sub>x</sub> emission control technology used to comply with the original BACT finding. The ammonia slip is limited to 5 ppm at 15% O<sub>2</sub> averaged over one hour. The standard approach to monitoring ammonia slip emissions is a mass balance formula that uses the exhaust flow rate, the NO<sub>x</sub> concentrations in the exhaust stack both before and after the SCR grid, and the ammonia injection rate to determine the amount of unreacted ammonia. Typically, this formula requires a correction factor that is re-evaluated once a year via source testing and is used to demonstrate compliance throughout the year. However, the District has modified the standard formula, eliminating the correction factor and negated the formula's use for demonstrating compliance with the ammonia slip limit without further corroborative evidence, which is not provided for in the condition. Thus, staff recommends that both the District formula and the standard formula be incorporated into Condition of Certification AQ-2. This would allow the District to further develop the formula for compliance purposes while

ensuring that the Energy Commission can rely on an established formula for compliance purposes.

### **Other Minor Changes**

Through the annual re-issuance of the District permits, the District has made minor changes in the wording and intent of some of the conditions. While these changes are not significant in nature and thus do not warrant individual assessments, they are significant enough to warrant adjustments to the Conditions of Certification. Therefore, staff has submitted explanations for each proposed modification in Appendix B.

### **Project Emission Changes and Mitigation**

The MVPC petition does not request any changes to the VOC, CO, SOx or PM10 emission limits or mitigation. Additionally, staff concludes that the petition does not hamper the Mountainview project from complying with their emission limits for these pollutants. The MVPC petition does request several changes that will require modification of the NOx RECLAIM Trading Credits (RTCs) the project must hold. Based on the analysis provided by the District, the first year of RTC holds for the Mountainview project are 492,897 lbs and the second year RTC holds are 464,338 lbs. These RTC holding requirements can change on an annual basis as the previous year's operation dictates. However, they represent a facility-wide emission limit since all emission producing devices must be accounted for, including (but not limited to) the combustion turbine stacks, the black-start engine and the firewater pump. RTC holdings are calculated on a 1:1 basis, and thus represent sufficient mitigation for the power project.

### **Conclusions and Recommendations**

Staff has analyzed the proposed changes and concludes that there are no new or additional significant impacts associated with approval of the petition. Staff concludes that the proposed changes are based on information that was not available during the original licensing proceeding. Staff concludes that the proposed language retains the intent of the original Energy Commission Decision and Conditions of Certification. Staff recommends that Condition of Certification AQ-13 be deleted and the following modifications to Conditions of Certification AQ-1, -2, -3, -4, -5, -6, -9, -10, -11, -12, -15, -16, -18, -19, -23, -24, -25, -28, -36 and -38.

**Proposed Modifications to the Air Quality Conditions of Certification**

Proposed modifications to the Conditions of Certification are shown below. Proposed additions are shown in underline and proposed deletions are shown in strike-through.

The Following Conditions apply to the following equipment

1,991 MMBTU/HR Gas Turbine (ID No. D18) (A/N ~~366147~~ 391557) No. 3-1 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B19) and a Heat Recovery Steam Generator (ID No. B20) with 135 MMBTU/HR Duct Burners (ID No. D21) connected in common with Gas Turbine No. 3-2 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B22). Selective Catalytic Reduction (ID No. C24) (A/N 366151) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B25) and a CO oxidation catalyst (ID No. C23) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S3526) (A/N ~~366146~~ 391557) No 3-1/~~3~~-2.

1,991 MMBTU/HR Gas Turbine (ID No. D27) (A/N ~~366148~~ 391558) No. 3-2 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B28) and a Heat Recovery Steam Generator (ID No. B29) with 135 MMBTU/HR Duct Burners (ID No. D30) connected in common with Gas Turbine No. 3-1 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B31). Selective Catalytic Reduction (ID No. C33) (A/N 366152) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B34) and a CO oxidation catalyst (ID No. C32) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S35) (A/N ~~366146~~ 391559) No ~~3-1~~/~~3~~-2.

1,991 MMBTU/HR Gas Turbine (ID No. D36) (A/N ~~366149~~ 391559) No. 4-3 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B37) and a Heat Recovery Steam Generator (ID No. B38) with 135 MMBTU/HR Duct Burners (ID No. D39) connected in common with Gas Turbine No. 4-4 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B40). Selective Catalytic Reduction (ID No. C42) (A/N 366153) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B43) and a CO oxidation catalyst (ID No. C41) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53 44) (A/N ~~366149~~ 391559) No 4-3/~~4~~-4.

1,991 MMBTU/HR Gas Turbine (ID No. D45) (A/N ~~366150~~ 391560) No. 4-4 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B46) and a Heat Recovery Steam Generator (ID No. B47) with 135 MMBTU/HR Duct Burners (ID No. D48) connected in common with Gas Turbine No. 4-3 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B49). Selective Catalytic Reduction (ID No.

C51) (A/N 366154) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B52) and a CO oxidation catalyst (ID No. C50) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53) (A/N 366150 391560) No 4-3/4-4.

**AQ-1** During the final phase of construction, the operator shall be allowed to exceed normal operational and startup emission limits and operational constraints (AQ-9, AQ-10, AQ-11, AQ-12, AQ-13 and AQ-14) and will be subject only to the limit prescribed in this Condition so that the turbine systems and controls can be fine tuned. This phase of construction is referred to herein as initial commissioning. ~~and shall be limited to no more than 33 operating days for each gas turbine following the date natural gas is first fired in that gas turbine.~~ The commissioning period shall not exceed 1,272 combined operating hours per two gas turbine power block from the time of initial startup. The power block is defined as two gas turbines that are connected to the same steam turbine. The project owner shall provide the District and Energy Commission with written notification of the initial startup date within two weeks of the startup.

~~If the turbine is loaded below 60%, the NOx emission factor used for RECLAIM purposes shall be 356 lbs/mmcf. If the turbine is loaded at or above 60%, the NOx emission factor used for RECLAIM purposes shall be 64 lbs/mmcf. No more than two turbine systems shall be in initial commissioning at one time. The project owner shall provide written notification to the District and California Energy Commission of the exact date natural gas is first fired in each of the four turbines, and the date, for each gas turbine, that commissioning activities are completed.~~

During the commissioning period and the interim reporting periods prior to the CEMS becoming validated by the District, the project owner shall report NOx emissions by using the recorded fuel use data and the assumed emission factor of 32.32 lbs/mmcf. Such record shall be made, kept and maintained on file for a minimum of five years and shall be made available to the District and the Energy Commission upon request. The facility log shall indicate the date, number of operating hours and fuel consumed for each turbine and duct burner during the commissioning period.

**Verification:** ~~The project owner and/or operator (project owner) shall report the turbine loading conditions (as a percent of maximum), duration of loading conditions (hours), the date of operation, the number of hours of operation, the natural gas fuel consumption during loading conditions (mmcf) and total NOx emissions during loading conditions (lbs) from initial commissioning to the California Energy Commission Compliance Project Manager (CPM) for each of the four gas turbines and duct burners no later than 10 days following the termination of the initial commissioning period for the last gas turbine in the monthly compliance report.~~

**AQ-2** ~~During the first 12 months of operation immediately following first fire, the project owner shall either (1) limit the annual natural gas fuel consumption for all four gas turbines and all four duct burners to no more than 35,000 MMCF or (2) demonstrate to the satisfaction of the South Coast Air Quality Management District (District) and the CPM that the total NOx emissions from all four gas turbines and duct burners will not exceed 250,302 pounds.~~

**Verification:** ~~The project owner shall submit total NOx emissions and natural gas fuel consumption reports to the CPM for the four gas turbines and duct burners as part of the Quarterly Operational Reports as described in Condition AQ-8. Requests to increase this emission limit shall be submitted to the District and CPM, and shall be accompanied by documentation evidencing that the Project Owner has sufficient RTCs to support the request.~~

**AQ-2** The owner/operator shall determine the hourly ammonia slip emissions from each exhaust stack for each gas turbine/HRSG train individually via both the following formulae:

District Requirement

$$\text{NH}_3 \text{ (ppmv)} = [a - b \cdot (c \cdot 1.2) / 1\text{E}6] \cdot 1\text{E}6 / b$$

Where:

a = NH3 injection rate (lb/hr) / 17 (lb/lbmol),

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The above described ammonia slip calculation procedure shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia for the District.

Energy Commission Requirement

$$\text{NH}_3 \text{ (ppmv @ 15\% O}_2\text{)} = ((a - b \cdot (c / 1\text{E}6)) \cdot 1\text{E}6 / b) \cdot d,$$

Where:

a = NH3 injection rate (lb/hr) / 17 (lb/lbmol),

b = dry exhaust gas flow rate (lb/hr) / (29 (lb/lbmol), or

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx concentration ppmv corrected to 15% O2 across catalyst, and

d = correction factor.

The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. The above describe ammonia slip calculation procedure shall be used for compliance determination and emission information determination for the Energy Commission.

The owner/operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

**Verification:** The project owner shall include ammonia slip concentrations averaged on an hourly basis calculated via both protocols provided as part of the Quarterly Operational Report required in Condition of Certification AQ-8. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date.

**AQ-3** The project owner shall install and maintain a continuous monitoring and recording system capable of measuring at least once every 15 minutes and recording measurements at least once every hour to accurately indicate the ammonia injection rate of the ammonia injection system. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

The project owner shall install and maintain a flow meter to accurately indicate and continuously record the flow rate of the water injection in gallons per minute for the turbine steam injection system.

Such records shall be and maintained on site per District requirements.

~~**Verification:** The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB), the United States Environmental Protection Agency (EPA) and the California Energy Commission (Commission). The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required ammonia injection rate monitor has been installed no later than 6 week after installation. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required flow meter has been installed no later than 6 week after installation. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required ammonia injection rate monitor has been calibrated as required no later than 6 week after calibration.~~

**AQ-4** The owner shall install and maintain a temperature gauge to accurately measure and record the temperature in the SCR catalyst. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

The operator shall install and maintain a pressure gauge to accurately indicate and continuously record the pressure drop across the SCR

catalyst bed in inches of water column. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

Such records shall be and maintained on site per District requirements.

**Verification:** ~~The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature gauge has been installed no later than 6 week after installation. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been installed no later than 6 week after installation. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature gauge has been calibrated as required no later than 6 week after calibration. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been calibrated as required no later than 6 week after calibration.~~

**AQ-5** The project owner shall install, maintain and operate no later than 90 days after the initial startup of the turbine a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to measure CO concentration in ppmv corrected to 15% oxygen on a dry basis and convert those CO concentrations to mass emission rates in units of pounds per hour (lbs/hr). The CEMS shall be capable of measuring at least over a 15-minute averaging period and shall record hourly mass emission rates on a continuous basis. The CEMS shall be installed and operated in accordance with an approved District Rule 218 CEMS plan application. The CEMS plan shall include a requirement for on going relative accuracy testing. The project owner shall NOT install the CEMS prior to receiving initial approval from the District.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission. The owner shall submit to the CPM a copy of the CEMS plan application submitted to the District and the initial written approval for installation from the District. No later than two weeks after the initial startup date of each turbine, the project owner shall provide written notification to the District and CPM of the exact date of startup.

**AQ-6** The project owner shall install, maintain and operate a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to continuously measure the concentrations of NOx (in ppmv) and oxygen in percent, fuel flow rate, and operational status codes as defined in

District Rule 2012 once every 15 minutes. In compliance with District Rule 2012, the project owner shall at least annually test the NOx CEMS for relative accuracy. The NOx CEMS shall record the combined NOx emissions from all four gas turbines and their respective duct burners whenever at least one gas turbine is in startup mode. The CEMS will convert all recorded the NOx concentrations to mass emissions and record NOx mass emissions hourly and daily. The CEMS shall be installed and operating no later than 12 months following first fire (District Rule 2021(h)(6)). From the time of first fire until the CEMS are certified, the project owner shall comply with the fuel monitoring requirements of District Rule 2012(h)(2) and 2012(h)(3).

**Verification:** The project owner shall make the site and appropriate records available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

**AQ-9** The project owner shall vent the gas turbine and duct burners to the SCR **and oxidation catalyst** control whenever the turbines or duct burners are in operation, including startup and normal operation. ~~The gas turbines shall not begin startup (defined as including the purge cycle) until the SCR has been preheated to a temperature of at least 500oF.~~

**Verification:** ~~The project owner shall submit SCR temperature recordings (see AQ-4) for each startup for each gas turbine in the Quarterly Operational Reports (see AQ-8). The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the gas turbine and HRSG exhausts connections to the SCR and oxidation catalysts are operational and air tight installed no later than 6 week after installation.~~

**AQ-10** Startup is defined for a gas turbine/HRSG train as beginning when fuel is introduced into the turbine's combustor, and ending immediately prior to the first 15-minute period when both the NOx and CO limits in Conditions AQ-11 are met. Cold-Startup is defined as a startup, as previously defined, which directly follows at least 72 hours of non-operation of the turbine. Shutdown is defined for a gas turbine/HRSG train as beginning at the start of the first 15-minute period when the NOx and CO limits in Condition AQ-11 are not met, and ending with the flow of fuel to the turbine's combustor ceases. Combustor-Tuning is defined as all manufacturer recommended activities required to ensure safe and reliable steady state operation of the gas turbine following the replacement of one (or more) of the turbine combustors. The project owner shall notify the District (via e-mail at [REFINERYENERGY@AQMD.GOV](mailto:REFINERYENERGY@AQMD.GOV)) and the CPM (by written letter) within two weeks of combustor tuning activities. ~~No more than two gas turbines shall be in startup mode at one time. The total duration of startups and shutdowns shall not exceed 4 3-hours per gas~~

turbine/HRSG per day. ~~While any gas turbine is in startup mode, the NO<sub>x</sub> emissions from all four turbines combined shall be limited to 75.54 lbs/hr. The duration of Cold-Startups may not exceed 6 hours per gas turbine/HRSG per day. The duration of Combustor-Tuning may not exceed 6 hours per gas turbine/HRSG per day. The NO<sub>x</sub> emissions from any gas turbine in startup mode shall be limited to 80.0 lbs/hr.~~ While any gas turbine is in startup mode, the NO<sub>x</sub> and CO emission limits in Condition AQ-11 shall not apply for that turbine. During a Startup, Shutdown, Cold Startup or Combustor Tuning event the following emission limits shall apply as indicated:

<u>NO<sub>x</sub> Emission Limit</u>	<u>Averaging Time</u>	<u>Operational Requirements</u>
<u>80 lbs/hour</u>	<u>1 hour</u>	<u>Applies only to a single turbine/HRSG train during Combustor-Tuning event.</u>
<u>160 lbs/hour</u>	<u>3 hours, rolling</u>	<u>Applies only to a single turbine/HRSG train only during a Startup or Cold-Startup event.</u>
<u>320 lbs/hour</u>	<u>1 hour</u>	<u>Applies to the combined emissions of all four turbine/HRSG trains whenever 1 or more turbines are in Startup or Cold-Startup mode.</u>

**Verification:** The project owner shall submit fuel use, NO<sub>x</sub> emissions and operational status on an hourly basis during each startup, ~~or shutdown, Cold-Startup or Combustor-Tuning event~~ for each gas turbine in the Quarterly Operational Reports (see AQ-8).

**AQ-11** Except during startup, shutdown, Cold-Startup, Combustor-Tuning, and initial commissioning and the exceptions noted below, emission from each gas turbine exhaust stack shall not exceed the following limits:

NO <sub>x</sub> (measured as NO <sub>2</sub> ):	<del>2.5</del> <u>2.0</u> ppm at 15% oxygen on a dry basis averaged over one hour and <del>17.77</del> <u>14.22</u> lbs/hour.
CO:	<u>6.0</u> ppm at 15% oxygen on a dry basis averaged over <del>3</del> <u>1</u> hours and 25.91 lbs/hr.
SO <sub>x</sub> (measured as SO <sub>2</sub> ):	1.42 lbs/hr
VOC:	3.47 lbs/hr
PM <sub>10</sub> :	11.0 lbs/hr
Ammonia:	5 ppm at 15% oxygen on a dry basis

**Exceptions:**

The NO<sub>x</sub> limit shall not apply to the first fifteen 1-hour average NO<sub>x</sub> emissions that are above 2.0 ppmv, dry basis at 15% O<sub>2</sub>, in any rolling 12-

month period for each combustion gas turbine provided that it meets all of the following requirements A, B, C and D:

A. This equipment operates under any one of the qualified conditions described below:

a) Rapid combustion turbine load changes due to the following conditions:

· Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control;

or

· Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load

**b) The first two 1-hour reporting periods following the initiation/shutdown of an evaporative cooler supply pump**

c) The first two 1-hour reporting periods following the initiation of HRSG duct burners.

d) Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees and the CPM.

B. The 1-hour average NO<sub>x</sub> emissions above 2.0 ppmv, dry basis at 15% O<sub>2</sub>, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).

C. The qualified operating conditions described in (A) above must be recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the data and time of entry into the log/CEMS and the plant operating conditions responsible for NO<sub>x</sub> emissions exceeding the 2.0 ppmv 1-hour average limit.

D. The 1-hour average NO<sub>x</sub> concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O<sub>2</sub>

All NO<sub>x</sub> emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

**Verification:** The project owner shall submit emission calculations to demonstrate compliance for the NO<sub>x</sub> and CO limits in the Quarterly Operational Reports (see AQ-8) and source tests, as required in Condition AQ-15, AQ-16 and AQ-17, to demonstrate compliance with SO<sub>x</sub>, VOC and PM<sub>10</sub> emission limits in the Quarterly Operational Reports (see AQ-8). Within 5 working days of the occurrence of an exception as described within this Condition, the

owner/operator shall notify the CPM. Within 21 working days, of the occurrence of an exception as described within this Condition, the owner/operator shall submit to the CPM a complete report of the exception event. That report must include, but is not limited to: the date, time, duration and cause of the occurrence, the emissions (in total mass and hourly concentration normalized to 15% O<sub>2</sub>) because of the occurrence and the evidence required in element (B) above.

**AQ-12** Except for initial commissioning, but including startup, ~~and shutdowns,~~ Cold-Startups and Combustor-Tunings the emissions from each gas turbine exhaust stack shall not exceed the following limits:

CO	8,610 lbs per month
<u>CO</u>	<u>694 lbs per day</u>
VOC	2,498 lbs per month
PM10	7,725 lbs per month
SOx	1,005 lbs per month

**Protocol:** The project owner shall confirm compliance with the monthly limits by using the monthly fuel use data of each gas turbine and duct burner pair and the following emission factors:

VOC	<del>4.64</del> <u>1.76</u> lbs/mmscf
PM10	<del>5.24</del> <u>5.57</u> lbs/mmscf
SOx (measured as SO <sub>2</sub> ):	<del>0.67</del> <u>0.71</u> lbs/mmscf

Compliance with the CO monthly limit shall be confirmed through the valid (per District Rule 218) CO CEMS or, absent valid CO CEMS, by the monthly fuel use data and the following emission factors:

<u>During Commissioning</u>	<u>114.47</u>	<u>lbs/mmscf</u>
<u>g</u>		<u>f</u>
<u>Following Commissioning</u>	<u>13.10</u>	<u>lbs/mmscf</u>
<u>g</u>		<u>f</u>

**Verification:** The project owner shall submit the monthly fuel use data and emission calculations to the CPM in the Quarterly Operation Reports (AQ-8).

**AQ-13** ~~Except for initial commissioning, the emissions shall not exceed the following limits: NO<sub>x</sub> (measured as NO<sub>2</sub>): 2 ppm at 15% oxygen from each gas turbine exhaust stack averaged over a year excluding periods of startup and shutdown as defined in Conditions AQ 10 and 235.9 tons~~

per year total for all four turbines/HRSGs, including periods of startup and shutdown as defined in Conditions AQ-10.

**Verification:** ~~The project owner shall submit all necessary data and emission calculations electronically to the CPM in the fourth Quarter Operation Report only (AQ-8) to verify compliance of the annual emission limits. The project owner shall submit to the CPM a copy of the annual RTC reconciliation report filed with the District within 10 days of the report's filing with the District.~~

**AQ-15** The project owner shall conduct an initial source test and annually thereafter for NOx, CO and NH3 and once every three years thereafter for SOx, VOC and PM10 of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the ~~Commission~~ CPM 45 days prior to the proposed initial source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- ~~The source test shall be conducted within 60 days of the approval of the source test protocol by the District, but no later than 180 days following the date of first fire.~~
- The initial source test shall be conducted no later than 180 days following the date of first fire.
- The District and ~~Commission~~ CPM shall be notified at least ~~40~~ 7 days prior to the date and time of the source test.
- The ~~initial~~ source test shall be conducted with the gas turbine operating under loads of 50%, 75% and 100% of maximum.
- The ~~initial~~ source test shall be conducted to determine the oxygen levels in the exhaust.
- The ~~initial~~ source test shall measure the fuel flow rate, the flue gas flow rate and the as turbine generating output.
- The ~~initial~~ source test shall be conducted for the pollutants listed using the methods, and averaging times, and test locations indicated and as approved by the CPM:

Polluta nt	Method	Averaging Time	<u>Test Location</u>
NOx	District Method 100.1	1 hour	<u>Outlet of SCR</u>
CO	District Method 100.1	<del>1 hour</del> <u>District Approved</u>	<u>Outlet of SCR</u>
SOx	<del>District Method 100.1</del> <u>District approved method</u>	<del>1 hour</del> <u>District Approved</u>	<u>Fuel Sample</u>
VOC	District approved	1 hour	<u>Outlet of SCR</u>

	method		
PM10	District approved method	<del>1 hour</del> <u>District Approved</u>	<u>Outlet of SCR</u>
Ammonia	<del>District approved method</del> <u>District Methods 5.3 and 207.1 or EPA Method 17.</u>	1 hour	<u>Outlet of SCR</u>

- The ~~initial~~ source test results shall be submitted to the District and the ~~Commission~~ CPM no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
  1. ppmv corrected to 15% oxygen,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned and
  4. additionally, for PM10 only, grains per dry standard cubic feet of fuel burned.

**Verification:** The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than ~~40~~ **7** days prior to the proposed initial source test date and time.

**AQ-16** The project owner shall conduct source testing of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the ~~Commission~~ CPM no later than ~~60~~ 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted quarterly for the first 12 months of operation and annually thereafter.
- NOx concentrations as determined by CEMS shall be simultaneously recorded during the ammonia test. If the NOx CEMS is inoperable, a test shall be conducted to determine the NOx emission by using District Method 100.1 measured over a 60 minute time period.
- Source testing shall be conducted to determine the ammonia emissions from each gas turbine exhaust stack using ~~an approved~~ District Method 5.3 and 207.1 or EPA Method 17 measured over a 1 hour averaging period.

- The District and ~~Commission~~ CPM shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the District and ~~Commission~~ CPM within 45 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The test shall be conducted when the equipment is operating at 80 percent load or greater.
- All emission data is to be expressed in the following units:
  1. ppmv corrected to 15% oxygen,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned and

**Verification:** The project owner shall submit the proposed protocol for the source tests ~~60~~ 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 7 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.

**The following Conditions of Certification pertain to the following equipment:**

~~Internal combustion engine, emergency power, diesel Caterpillar 3512B, electronically controlled, turbocharged, aftercooled, 2200 BHP A/N 366155 (ID. No. D54).~~

Internal combustion engine, emergency power, diesel Caterpillar 3612, 4° timing retard, turbocharged, aftercooled, 5900 BHP A/N 366155 (ID. No. D54).

**AQ-18** The project owner shall not use fuel oil containing sulfur compounds in excess of ~~0.05 percent~~ 15 ppm by weight as supplied by the supplier.

**Verification:** The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Energy Commission (see AQ-21).

**~~AQ-19 Deleted~~** The project owner shall set and maintain the fuel injection timing of the emergency IC engine at 4° retarded relative to standard timing.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

**AQ-23** The project owner shall limit the operating time of the emergency IC engine to no more than ~~200~~ **199** hours per year.

**Verification:** The project owner shall submit the recorded data specified in condition AQ-21 on an annual basis as part of the fourth Quarter Operational Report (see AQ-8).

**The following Conditions of Certification pertain to the following equipment:**

Internal combustion engine, emergency fire pump, diesel ~~Cummins 6BTA~~ Clarke Model JW6H-UF60, 4 9.7<sup>0</sup> timing retard, turbocharged, aftercooled, ~~482~~ 375 BHP A/N 366156 (ID. No. D55-58).

**AQ-24** The project owner shall not use fuel oil containing sulfur compounds in excess of ~~0.05 percent~~ 15 ppm by weight as supplied by the supplier.

**Verification:** The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Energy Commission (see AQ-27).

**AQ-25** The project owner shall set and maintain the fuel injection timing of the fire pump IC engine at 4 9.7<sup>0</sup> retarded relative to standard timing.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

**AQ-28** The project owner shall limit the operating time of the fire pump IC engine to no more than ~~200~~ 199 hours per year.

**Verification:** The project owner shall submit the recorded data specified in condition AQ-27 on an annual basis as part of the fourth Quarter Operational Report (see AQ-8).

**AQ-36** The gas turbines shall not be operated unless the operator demonstrates to the District and CPM that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, the gas turbines shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

The owner/operator shall limit the first year, defined as the first 12 months following initial operation, cumulative facility wide NOx emissions from all equipment to no more than 492,897 lbs/year.

The owner/operator shall, prior to the beginning of all years subsequent to the first year (as defined above), hold a minimum of 464,338 lbs of NOx RTCs for the operation of all equipment at the facility.

In accordance with District Rule 2005 (f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year.

**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District in each Quarterly Operational Report. (see AQ-8).

**The following Conditions of Certification pertain to the following equipment:**

~~Storage tank, TK-1, serving SCRs 3-1 and 3-2 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366162 (ID No. D56).~~

~~Storage tank, TK-2, serving SCRs 4-3 and 4-4 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366163 (ID No. D57).~~

Storage tank, TK-3, aqueous ammonia, 24.5% wt., serving SCRs 3-1, 3-2, 4-3, 4-4, with a vapor return line, ~~22,500~~ 36,000 gallons (ID No. D60)

**AQ-38** The project owner shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig in the aqueous ammonia storage tank.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

## **Appendix A**

### **Emission and Air Quality Impacts Calculations**

### **Revised BACT Emission Estimates**

The District has revised the BACT finding for Mountainview as follows:

NOx: from 2.5 ppm to 2.0 ppm at 15% O<sub>2</sub> averaged over one hour.

Staff estimates that the 1-hour mass emission limits will decrease as follows because of these revised BACT findings:

NOx: from 17.77 lbs/hr to 14.22 lbs/hr averaged over 1-hour.

### **Exceptions**

MVPC is not expected to use the exception allowance that has been provided to them by the District, because MVPC is proposing to run Mountainview as a base loaded facility. Non the less, the exception language, which was developed in response to a concern raised by the Inland Empire Energy Center (IEEC), is incorporated in this case. IEEC facility intends to operate as a load-follower or peaker; thus, they expect to change load frequently. Under some conditions, IEEC was concerned that the project, while under Independent System Operator (ISO) control, may experience significant load changes. Since the project operator would not be in direct control of these load changes, they did not want to take responsibility for any exceedances of permit limits that may occur as a result. Thus, the exception language was developed to alleviate these concerns.

### **Initial Commissioning Emission Estimates**

MVPC is requesting, based primarily on advice from General Electric, that the Mountainview turbines be allowed to perform commissioning activities limited to 636 hours, rather than 33 days. Assuming 12 hour operational days, this results in an additional 20 days of commissioning for each turbine. In calculating commissioning emissions, it is important to consider the various major stages of commissioning. To summarize, the major stages of commissioning are (1) Full-Speed-No-Load which includes ignition testing, (2) Part-Load testing, (3) Full-Load without SCR or oxidation catalyst, (4) Full-Load with SCR and oxidation catalyst at partial control, and (5) Full-Load with SCR and oxidation catalyst at full control. AIR QUALITY Appendix A Table 1 shows the various major commissioning stages with the assumed number of days for each stage and proposed increases. It is important to understand that the actual request is limited to an increase from **33 days to 636 hours**. The other values (e.g., proposed number of days) in AIR QUALITY Appendix A Table 1 are estimates and the MVPC will not be held to them. However, these are the same assumptions that were made in the original licensing case to estimate the initial commissioning emissions. The estimated emission factors in AIR QUALITY Appendix A Table 2 are the same emission factors used in the original licensing case. AIR QUALITY Tables 3 through 5 show the hourly, daily and total expected commissioning emissions for each turbine based on the proposed limit of 636 hours. For all four turbines, the total expected commissioning emissions are 115,984 lbs of NOx, 727,244 lbs of CO, 11,368 lbs of VOC, 2,840 lbs, of Sox, and 111,520 lbs of PM10.

**AIR QUALITY Appendix A Table 1**  
**Estimated Commissioning Time and Firing Rate**

	<b>Estimated Days</b>		<b>Estimated Operation</b>	<b>Firing Rate</b>
	<b>Current</b>	<b>Proposed</b>	<b>(hours/day)</b>	<b>(MMBtu/hr)</b>
Full Speed, No Load	5	8	12	400
Part Load test	6	10	12	1,160
Full Load Test (FLT)	4	6	12	1,991
FLT w/SCR part. contrl.	5	9	12	1,991
FLT, SCR full contrl.	13	20	12	1,991
<b>Total</b>	<b>33 days</b>	<b>53 days 636 hours</b>		

**AIR QUALITY Appendix A Table 2**  
**Estimated Commissioning Emission Rates**

	<b>Estimated Emission Factors (lbs/MMBtu)</b>				
	<b>NOx</b>	<b>CO</b>	<b>VOC</b>	<b>SOx</b>	<b>PM10</b>
Full Speed, No Load	0.3125	0.9625	0.008	0.0007	0.0275
Part Load test	0.0427	0.9625	0.008	0.0007	0.0275
Full Load Test (FLT)	0.032	0.013	0.0017	0.0007	0.0275
FLT w/SCR part. contrl.	0.0142	0.013	0.0017	0.0007	0.0275
FLT, SCR full contrl.	0.00714	0.013	0.0017	0.0007	0.0275

**AIR QUALITY Appendix A Table 3**  
**Estimated Commissioning Hourly Emissions per Turbine**

	<b>Estimated Emissions (lbs/hour)</b>				
	<b>NOx</b>	<b>CO</b>	<b>VOC</b>	<b>SOx</b>	<b>PM10</b>
Full Speed, No Load	125	385	3.2	0.28	11
Part Load test	49.53	1116.5	9.28	0.81	31.90
Full Load Test (FLT)	63.71	25.88	3.38	1.39	54.75
FLT w/SCR part. contrl.	28.27	25.88	3.38	1.39	54.75
FLT, SCR full contrl.	14.22	25.88	3.38	1.39	54.75

**AIR QUALITY Appendix A Table 4**  
**Estimated Commissioning Daily Emissions per Turbine**

	<b>Estimated Emissions (lbs/day)</b>				
	<b>NOx</b>	<b>CO</b>	<b>VOC</b>	<b>SOx</b>	<b>PM10</b>

Full Speed, No Load	1500	4620	38.4	3.36	132
Part Load test	594.38	13398	111.36	9.74	382.80
Full Load Test (FLT)	764.54	310.60	40.62	16.72	657.03
FLT w/SCR part. contrl.	339.27	310.60	40.62	16.72	657.03
FLT, SCR full contrl.	170.59	310.60	40.62	16.72	657.03

**AIR QUALITY Appendix A Table 5**  
**Estimated Total Commissioning Emissions per Turbine**

	<b>Estimated Emissions (lbs/commissioning)</b>				
	<b>NOx</b>	<b>CO</b>	<b>VOC</b>	<b>SOx</b>	<b>PM10</b>
Full Speed, No Load	12,000	36,960	307	27	1,056
Part Load test	5,944	133,980	1,114	97	3,828
Full Load Test (FLT)	4,587	1,864	244	100	3,942
FLT w/SCR part. contrl.	3,053	2,795	366	151	5,913
FLT, SCR full contrl.	3,412	6,212	812	334	13,141
Total	28,996	181,811	2,842	710	27,880

#### **Startup & Cold-Startup Emission Estimates**

MVPC has requested that the startup duration limit be increased from three hours to four hours, and six hours allowed for a "cold startup". A cold startup is defined as a start up that occurs after the combustion turbine and HRSG have been off-line and not firing fuel for 72 hours or more. In a previous petition, MVPC was granted an emission limit increase to 80 lbs/hour of NOx during startup. However, the District has determined that this will be insufficient for the facility to perform a simultaneous startup of all four turbine trains. Through negotiations with MVPC and an examination of the available data, the District has agreed to the limits shown in AIR QUALITY Appendix A Table 6.

**AIR QUALITY Appendix A Table 6**  
**District Imposed Startup Emission Limits**

<b>NOx Emission Limit</b>	<b>Averaging Time</b>	<b>Operational Requirements</b>
<b>160 lbs/hour</b>	<b>3 hours, rolling</b>	<b>Applies to a single turbine/HRSG train only during a Startup or Cold-Startup event.</b>
<b>320 lbs/hour</b>	<b>1 hour</b>	<b>Applies to the combined emissions of all four turbine/HRSG trains whenever 1 or more turbines are in Startup or Cold-Startup mode.</b>

### **Periodic Combustor Tuning Emission Estimates**

In some cases, GE Frame 7FA combustion turbines have experienced periodic failures of DLN combustor components. These failures require the combustor components to be replaced and the turbine re-tuned. This re-tuning may produce higher emissions than under normal operating conditions. Thus, while re-tuning, it is unlikely that the turbine will be able to comply with the normal operating emission constraints. MVPC proposes to treat this re-tuning period similar to a cold startup, proposing that it take no longer than 6 hours to perform. MVPC has proposed a NO<sub>x</sub> emission limit of 80 lbs/hr during these combustor tuning events. The District has accepted this limit and incorporated it into the permit conditions.

### **Expected Black Start Engine Emissions**

In a previous amendment, MVPC petitioned the Energy Commission to approve a smaller diesel powered black-start engine for Mountainview. The original black-start engine was 5,900 bhp in size and had significant emissions that were fully mitigated. The smaller black-start engine was proposed to be 2,200 bhp, would have been newer and have lower emission rates. However, MVPC has determined that they are uncertain as to the eventual size of the black-start engine. Since the modification to the black-start engine was never completed in the District permits, MVPC is requesting that the Energy Commission Conditions of Certification retain the original size and emission profile of the 5,900 bhp black-start engine. This will require that Condition AQ-19 be reinstated and that the equipment description paragraph within the Conditions of Certification be revised. Additionally, the NO<sub>x</sub> RTC requirements will need to reflect the NO<sub>x</sub> emission from the required periodic testing of the 5,900 bhp black-start engine.

From the original licensing case for Mountainview, the 5,900 bhp black-startup engine emissions are expected to be as shown in AIR QUALITY Appendix A Table 7.

**AIR QUALITY Appendix A Table 7**  
**Expected Emission from Black-Start Diesel Engine**

<b>Averaging Period</b>	<b>NO<sub>x</sub></b>	<b>SO<sub>x</sub></b>	<b>CO</b>	<b>VOC</b>	<b>PM<sub>10</sub></b>
lbs/hour	20.7	0.44	1.56	1.56	0.81
lbs/day (1-hour testing)	20.7	0.44	1.56	1.56	0.81
lbs/year	4115	88	310	310	161

### **Expected Firewater Pump Emissions**

MVPC is proposing to substitute a Clarke 375 bhp diesel engine to serve as the firewater pump for the Cummins 182 bhp diesel engine for which they were

originally licensed. Although the engine size is significantly larger, the engine is newer and must comply with more stringent emission limitations set by the California Air Resources Board (CARB). However, the expected emissions of NO<sub>x</sub> and CO will approximately double, although the PM<sub>10</sub> and VOC emissions will be less than half of those from the older engine. The SO<sub>x</sub> emissions will not substantially change due to the use of CARB Ultra Low-Sulfur Diesel Fuel. The quantity of NO<sub>x</sub> and CO (4.2 lbs/hr and 0.405 lbs/hr respectively) do not represent a significant amount of emissions. Therefore, staff is confident that the Mountainview project can operate well within its monthly emission limits for CO and the annual RECLAIM limits for NO<sub>x</sub>.

AIR QUALITY Appendix A Table 8 shows the expected differences in emissions between the Cummins 182 bhp engine and the Clarke 375 bhp engine. Based on these differences, the expected annual emission increases for the Clarke engine are shown in AIR QUALITY Appendix A Table 9.

**AIR QUALITY Appendix A Table 8**  
**Expected Change in Emission from New Firewater Pump Engine**  
**(lbs/hour)**

Engine	NO <sub>x</sub>	SO <sub>x</sub>	CO	VOC	PM <sub>10</sub>
Clarke 375 bhp	4.213	0.116	0.405	0.149	0.074
Cummins 182 bhp	1.98	0.063	0.53	0.31	0.10
Increase in mass emission	2.23	0.053	-0.125	-0.161	-0.926

**AIR QUALITY Appendix A Table 9**  
**Expected Change in Emission from New Firewater Pump Engine**  
**(lbs/year)**

Engine	NO <sub>x</sub>	SO <sub>x</sub>	CO	VOC	PM <sub>10</sub>
Clarke 375 bhp	841.3	23.2	81.0	29.8	14.8
Cummins 182 bhp	394.0	12.5	105.5	61.7	19.9
Increase in mass emission	447	10.7	-24.5	-31.9	-5.1

Assumes 199 hours of operation

### **Comparison of NO<sub>x</sub> Emission Limits with Required Mitigation**

Combining the expected first year emissions from the power blocks (see AIR QUALITY Appendix A Table 10) with the emissions from the black-start engine and the firewater pump (494,092 lbs + 841 lbs + 4,115 lbs) totals 499,048 lbs. Since the emissions detailed in AIR QUALITY Appendix A Table 10 are estimated, MVPC has requested the annual NO<sub>x</sub> limit (and required RTC holding) be placed at 492,897 lbs. Since the District permit is federally enforceable and this is less than a 2% change in the annual emissions, staff has

no objection. The Second year emissions from the power block, black start engine and firewater pump are 464,338 lbs. These emission restrictions correspond to the emission limits in Condition of Certification AQ-36 and represent the required NOx RTC holding. Therefore, staff finds that the potential NOx emission increase as a result of the MVPC petition to the Energy Commission is fully mitigated and does not represent a significant impact to the ambient air quality.

**AIR QUALITY Appendix A Table 10**  
**First and Second Year Annual Expected Emissions of the Power Blocks**

	<b>Annual Operation</b>	<b>Annual Emissions</b>	
	<b>(hours/year)</b>	<b>total lbs</b>	<b>total tons</b>
Hot Starts	2080	166400	83.20
Warm Starts	728	58240	29.12
Cold-Starts/Combustor-Tuning	200	16000	8.00
Normal Operation			
115 °F, with duct firing	40	511	0.26
82 °F, with duct firing	1686	22458	11.23
59 °F, without duct firing	7145	91170	45.59
26 °F, without duct firing	5699	75284	37.64
26 °F, witht duct firing	2072	29319	14.66
12-Month Total (Second Year)	19650	459382	229.69
Average per Month	1638	38282	459.4
Commission Emissions + 10 Months of Average Emissions	--	494092	247.0

## **Appendix B**

### **Clarifications of Proposed Amendments to Conditions of Certification**

**Proposed Modifications to the Air Quality Conditions of Certification**

Proposed modifications to the Conditions of Certification are shown below. Proposed additions are shown in bold and proposed deletions are shown in strike-through. Discussions of each modification are included within text-boxes where appropriate near the subject condition, but are not intended as proposed additions.

In the following four paragraphs of equipment description for the combustion turbine trains (which include the gas turbine, HRSG and steam turbine), A/N numbers have been updated, clarifications for nominal capacity at ISO have been made and stack ID numbers have been updated to reflect the separation of stacks

1,991 MMBTU/HR Gas Turbine (ID No. D18) (A/N ~~366147~~ 391557) No. 3-1 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B19) and a Heat Recovery Steam Generator (ID No. B20) with 135 MMBTU/HR Duct Burners (ID No. D21) connected in common with Gas Turbine No. 3-2 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B22). Selective Catalytic Reduction (ID No. C24) (A/N 366151) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B25) and a CO oxidation catalyst (ID No. C23) with 240 cubic feet of total volume connected to an exhaust stack (ID No. ~~S3526~~) (A/N ~~366146~~ 391557) No 3-1/~~3~~-2.

1,991 MMBTU/HR Gas Turbine (ID No. D27) (A/N ~~366148~~ 391558) No. 3-2 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B28) and a Heat Recovery Steam Generator (ID No. B29) with 135 MMBTU/HR Duct Burners (ID No. D30) connected in common with Gas Turbine No. 3-1 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B31). Selective Catalytic Reduction (ID No. C33) (A/N 366152) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B34) and a CO oxidation catalyst (ID No. C32) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S35) (A/N ~~366146~~ 391559) No ~~3-1~~/~~3~~-2.

1,991 MMBTU/HR Gas Turbine (ID No. D36) (A/N ~~366149~~ 391559) No. 4-3 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B37) and a Heat Recovery Steam Generator (ID No. B38) with 135 MMBTU/HR Duct Burners (ID No. D39) connected incommon with Gas Turbine No. 4-4 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B40). Selective Catalytic Reduction (ID No. C42) (A/N 366153) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B43) and a CO oxidation catalyst (ID No. C41) with 240 cubic feet of total volume connected to an exhaust stack (ID No. ~~S53~~ 44) (A/N ~~366149~~ 391559) No 4-3/~~4~~-4.

1,991 MMBTU/HR Gas Turbine (ID No. D45) (A/N 366150 391560) No. 4-4 GE Model 7FA with Dry Low NOx combustors connected directly to a 175.7 MW (nominal at ISO conditions) Electric Generator (ID No. B46) and a Heat Recovery Steam Generator (ID No. B47) with 135 MMBTU/HR Duct Burners (ID No. D48) connected in common with Gas Turbine No. 4-3 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B49). Selective Catalytic Reduction (ID No. C51) (A/N 366154) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.6 feet wide with an ammonia injection grid (ID No. B52) and a CO oxidation catalyst (ID No. C50) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53) (A/N 366150 391560) No 4-3/4-4.

AQ-1 has been modified to expand the commissioning period and provide for the appropriate NOx emission recording and reporting.

**AQ-1** During the final phase of construction, the operator shall be allowed to exceed normal operational and startup emission limits and operational constraints (AQ-9, AQ-10, AQ-11, AQ-12, AQ-13 and AQ-14) and will be subject only to the limit prescribed in this Condition so that the turbine systems and controls can be fine tuned. This phase of construction is referred to herein as initial commissioning. ~~and shall be limited to no more than 33 operating days for each gas turbine following the date natural gas is first fired in that gas turbine.~~ The commissioning period shall not exceed 1,272 combined operating hours per two gas turbine power block from the time of initial startup. The power block is defined as two gas turbines that are connected to the same steam turbine. The project owner shall provide the District and Energy Commission with written notification of the initial startup date within two weeks of the startup.

~~If the turbine is loaded below 60%, the NOx emission factor used for RECLAIM purposes shall be 356 lbs/mmcf. If the turbine is loaded at or above 60%, the NOx emission factor used for RECLAIM purposes shall be 64 lbs/mmcf. No more than two turbine systems shall be in initial commissioning at one time. The project owner shall provide written notification to the District and California Energy Commission of the exact date natural gas is first fired in each of the four turbines, and the date, for each gas turbine, that commissioning activities are completed.~~

During the commissioning period and the interim reporting periods prior to the CEMS becoming validated by the District, the project owner shall report NOx emissions by using the recorded fuel use data and the assumed emission factor of 32.32 lbs/mmcf. Such record shall be made, kept and maintained on file for a minimum of five years and shall be made available to the District and the Energy Commission upon request. The facility log

shall indicate the date, number of operating hours and fuel consumed for each turbine and duct burner during the commissioning period.

**Verification:** The project owner and/or operator (project owner) shall report the turbine loading conditions (as a percent of maximum), duration of loading conditions (hours), the date of operation, the number of hours of operation, the natural gas fuel consumption during loading conditions (mmcf) and total NOx emissions during loading conditions (lbs) from initial commissioning to the California Energy Commission Compliance Project Manager (CPM) for each of the four gas turbines and duct burners no later than 10 days following the termination of the initial commissioning period for the last gas turbine with the monthly compliance report.

AQ-2 has been deleted by the District, which is relying on the RECLAIM NOx/RTC limit in AQ-36 to perform the same task. Replacing AQ-2 is the ammonia tracking requirement that has been imposed by the District, in addition to an ammonia tracking requirement that staff recommends be imposed by the Energy Commission. Although this may seem redundant, the District condition does not require the project owner to use the ammonia tracking formula for

**AQ-2** During the first 12 months of operation immediately following first fire, the project owner shall either (1) limit the annual natural gas fuel consumption for all four gas turbines and all four duct burners to no more than 35,000 MMCF or (2) demonstrate to the satisfaction of the South Coast Air Quality Management District (District) and the CPM that the total NOx emissions from all four gas turbines and duct burners will not exceed 250,302 pounds.

**Verification:** The project owner shall submit total NOx emissions and natural gas fuel consumption reports to the CPM for the four gas turbines and duct burners as part of the Quarterly Operational Reports as described in Condition AQ-8. Requests to increase this emission limit shall be submitted to the District and CPM, and shall be accompanied by documentation evidencing that the Project Owner has sufficient RTCs to support the request.

**AQ-2** The owner/operator shall determine the hourly ammonia slip emissions from each exhaust stack for each gas turbine/HRSG train individually via both the following formulae:

District Requirement

NH3 (ppmv) = [a-b\*(c\*1.2)/1E6]\*1E6/b

Where:

a = NH3 injection rate (lb/hr) / 17(lb/lbmole),

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The above described ammonia slip calculation procedure shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia for the District.

Energy Commission Requirement

$NH_3$  (ppmv @ 15% O<sub>2</sub>) = ((a-b\*(c/1E6))\*1E6/b)\*d.

Where:

a = NH<sub>3</sub> injection rate(lb/hr)/17(lb/lbmol),

b = dry exhaust gas flow rate (lb/hr)/(29(lb/lbmol), or

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NO<sub>x</sub> concentration ppmv corrected to 15% O<sub>2</sub> across catalyst, and

d = correction factor.

The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. The above describe ammonia slip calculation procedure shall be used for compliance determination and emission information determination for the Energy Commission.

The owner/operator shall install a NO<sub>x</sub> analyzer to measure the SCR inlet NO<sub>x</sub> ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

**Verification:** The project owner shall include ammonia slip concentrations averaged on an hourly basis calculated via both protocols provided as part of the Quarterly Operational Report required in Condition of Certification AQ-8. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date.

The District has included several new conditions requiring more specificity on the ammonia injection system and a water injection flow meter. While these requirements are clearly necessary to regulate the ultimate project emissions, their installation and use is routine and thus do not require significant additional

**AQ-3** The project owner shall install and maintain a continuous monitoring and recording system capable of measuring at least once every 15 minutes and recording measurements at least once every hour to accurately indicate the ammonia injection rate of the ammonia injection system. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

The project owner shall install and maintain a flow meter to accurately indicate and continuously record the flow rate of the water injection in gallons per minute for the turbine steam injection system.

Such records shall be and maintained on site per District requirements.

**Verification:** ~~The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB), the United States Environmental Protection Agency (EPA) and the California Energy Commission (Commission).~~ The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required ammonia injection rate monitor has been installed no later than 6 week after installation. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required flow meter has been installed no later than 6 week after installation. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required ammonia injection rate monitor has been calibrated as required no later than 6 week after calibration.

The District has included several new conditions requiring more specificity on the SCR system, including a pressure monitor as well as a temperature monitor. While these requirements are clearly necessary to regulate the ultimate project emissions, their installation and use is routine and thus do not require significant additional

**AQ-4** The owner shall install and maintain a temperature gauge to accurately measure and record the temperature in the SCR catalyst. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

The operator shall install and maintain a pressure gauge to accurately indicate and continuously record the pressure drop across the SCR catalyst bed in inches of water column. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

Such records shall be and maintained on site per District requirements.

**Verification:** ~~The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.~~ The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature gauge has been installed no later than 6 week after installation. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been installed no later than 6 week after installation. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature gauge has been calibrated as required no later than 6 week

after calibration. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been calibrated as required no later than 6 week after calibration.

This is a minor adjustment to reflect the existing requirements within District Rule 218.

**AQ-5** The project owner shall install, maintain and operate no later than 90 days after the initial startup of the turbine a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to measure CO concentration in ppmv corrected to 15% oxygen on a dry basis and convert those CO concentrations to mass emission rates in units of pounds per hour (lbs/hr). The CEMS shall be capable of measuring at least over a 15-minute averaging period and shall record hourly mass emission rates on a continuous basis. The CEMS shall be installed and operated in accordance with an approved District Rule 218 CEMS plan application. The CEMS plan shall include a requirement for on going relative accuracy testing. The project owner shall NOT install the CEMS prior to receiving initial approval from the District.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission. The owner shall submit to the CPM a copy of the CEMS plan application submitted to the District and the initial written approval for installation from the District. No later than two weeks after the initial startup date of each turbine, the project owner shall provide written notification to the District and CPM of the exact date of startup.

This modification is required to provide the applicant with the ability to demonstrate compliance with the new District proposed startup limits provided in AQ-10. One of these startup limits is for all four turbine trains; therefore, the NOx emissions will need to be collected while some trains are

**AQ-6** The project owner shall install, maintain and operate a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to continuously measure the concentrations of NOx (in ppmv) and oxygen in percent, fuel flow rate, and operational status codes as defined in District Rule 2012 once every 15 minutes. In compliance with District Rule 2012, the project owner shall at least annually test the NOx CEMS for relative accuracy. The NOx CEMS shall record the combined NOx emissions from all four gas turbines and their respective duct burners whenever at least one gas turbine is in startup mode. The CEMS will convert all recorded the NOx concentrations to mass emissions and record NOx mass emissions hourly

and daily. The CEMS shall be installed and operating no later than 12 months following first fire (District Rule 2021(h)(6)). From the time of first fire until the CEMS are certified, the project owner shall comply with the fuel monitoring requirements of District Rule 2012(h)(2) and 2012(h)(3).

**Verification:** The project owner shall make the site and appropriate records available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

This modification is necessary because the old, existing boiler units that were to provide pre-heating to the steam turbine and HRSGs have been de-commissioned and are no longer available for use. The addition of the oxidation

**AQ-9** The project owner shall vent the gas turbine and duct burners to the SCR and oxidation catalyst control whenever the turbines or duct burners are in operation, including startup and normal operation. ~~The gas turbines shall not begin startup (defined as including the purge cycle) until the SCR has been preheated to a temperature of at least 500oF.~~

**Verification:** ~~The project owner shall submit SCR temperature recordings (see AQ-4) for each startup for each gas turbine in the Quarterly Operational Reports (see AQ-8). The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the gas turbine and HRSG exhausts connections to the SCR and oxidation catalysts are operational and air tight installed no later than 6 week after installation.~~

This modification includes the new proposed startup limits, definitions and limits for cold-startups and combustor-tuning.

**AQ-10** Startup is defined for a gas turbine/HRSG train as beginning when fuel is introduced into the turbine's combustor, and ending immediately prior to the first 15-minute period when both the NOx and CO limits in Conditions AQ-11 are met. Cold-Startup is defined as a startup, as previously defined, which directly follows at least 72 hours of non-operation of the turbine. Shutdown is defined for a gas turbine/HRSG train as beginning at the start of the first 15-minute period when the NOx and CO limits in Condition AQ-11 are not met, and ending with the flow of fuel to the turbine's combustor ceases. Combustor-Tuning is defined as all manufacturer recommended activities required to ensure safe and reliable steady state operation of the gas turbine following the replacement of one (or more) of the turbine combustors. The project owner shall notify the District (via e-mail at [REFINERYENERGY@AQMD.GOV](mailto:REFINERYENERGY@AQMD.GOV)) and the CPM (by written letter) within two weeks of combustor tuning activities. ~~No more than two gas turbines~~

~~shall be in startup mode at one time. The total duration of startups and shutdowns shall not exceed 4 3-hours per gas turbine/HRSG per day. While any gas turbine is in startup mode, the NOx emissions from all four turbines combined shall be limited to 75.54 lbs/hr. The duration of Cold-Startups may not exceed 6 hours per gas turbine/HRSG per day. The duration of Combustor-Tuning may not exceed 6 hours per gas turbine/HRSG per day. The NOx emissions from any gas turbine in startup mode shall be limited to 80.0 lbs/hr. While any gas turbine is in startup mode, the NOx and CO emission limits in Condition AQ-11 shall not apply for that turbine. During a Startup, Shutdown, Cold Startup or Combustor Tuning event the following emission limits shall apply as indicated:~~

<u>NOx Emission Limit</u>	<u>Averaging Time</u>	<u>Operational Requirements</u>
<u>80 lbs/hour</u>	<u>1 hour</u>	<u>Applies only to a single turbine/HRSG train during Combustor-Tuning event.</u>
<u>160 lbs/hour</u>	<u>3 hours, rolling</u>	<u>Applies only to a single turbine/HRSG train only during a Startup or Cold-Startup event.</u>
<u>320 lbs/hour</u>	<u>1 hour</u>	<u>Applies to the combined emissions of all four turbine/HRSG trains whenever 1 or more turbines are in Startup or Cold-Startup mode.</u>

**Verification:** The project owner shall submit fuel use, NOx emissions and operational status on an hourly basis during each startup, ~~or shutdown, Cold-Startup or Combustor-Tuning event~~ for each gas turbine in the Quarterly Operational Reports (see AQ-8).

This modification reflects the new BACT finding for NOx by the District as well as the exceptions to that finding. Additionally, the CO limit has been clarified by the District to be 6.0 instead of 6 (to reflect a level of accuracy) and the averaging time has been corrected from 3 hours to 1 hour

**AQ-11** Except during startup, shutdown, Cold-Startup, Combustor-Tuning, and initial commissioning, and the exceptions noted below, emission from each gas turbine exhaust stack shall not exceed the following limits:

NOx (measured as NO <sub>2</sub> ):	<del>2.5</del> <u>2.0</u> ppm at 15% oxygen on a dry basis averaged over one hour and <del>17.77</del> <u>14.22</u> lbs/hour.
CO:	<del>6.0</del> <u>6.0</u> ppm at 15% oxygen on a dry basis averaged over <del>3</del> <u>1</u> hours and 25.91 lbs/hr.

SOx (measured as SO <sub>2</sub> ):	1.42 lbs/hr
VOC:	3.47 lbs/hr
PM <sub>10</sub> :	11.0 lbs/hr
Ammonia:	5 ppm at 15% oxygen on a dry basis

Exceptions:

The NOx limit shall not apply to the first fifteen 1-hour average NOx emissions that are above 2.0 ppmv, dry basis at 15% O<sub>2</sub>, in any rolling 12-month period for each combustion gas turbine provided that it meets all of the following requirements A, B, C and D:

A. This equipment operates under any one of the qualified conditions described below:

a) Rapid combustion turbine load changes due to the following conditions:

· Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control;

or

· Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load

**b) The first two 1-hour reporting periods following the initiation/shutdown of an evaporative cooler supply pump**

c) The first two 1-hour reporting periods following the initiation of HRSG duct burners.

d) Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees and the CPM.

B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O<sub>2</sub>, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).

C. The qualified operating conditions described in (A) above must be recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the data and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1-hour average limit.

D. The 1-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O<sub>2</sub>

All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

**Verification:** The project owner shall submit emission calculations to demonstrate compliance for the NOx and CO limits ~~in the Quarterly Operational Reports (see AQ-8)~~ and source tests, as required in Condition AQ-15, AQ-16 and AQ-17, to demonstrate compliance with SOx, VOC and PM10 emission limits in the Quarterly Operational Reports (see AQ-8). Within 5 working days of the occurrence of an exception as described within this Condition, the owner/operator shall notify the CPM. Within 21 working days, of the occurrence of an exception as described within this Condition, the owner/operator shall submit to the CPM a complete report of the exception event. That report must include, but is not limited to: the date, time, duration and cause of the occurrence, the emissions (in total mass and hourly concentration normalized to 15% O<sub>2</sub>) because of the occurrence and the evidence required in element (B) above.

This modification updates the fuel based emission factors to be used for the demonstration of compliance and the addition of a new CO daily limit.

**AQ-12** Except for initial commissioning, but including startup, ~~and shutdowns, Cold-Startups and Combustor-Tunings~~ the emissions from each gas turbine exhaust stack shall not exceed the following limits:

CO	8,610 lbs per month
<u>CO</u>	<u>694 lbs per day</u>
VOC	2,498 lbs per month
PM10	7,725 lbs per month
SOx	1,005 lbs per month

**Protocol:** The project owner shall confirm compliance with the monthly limits by using the monthly fuel use data of each gas turbine and duct burner pair and the following emission factors:

VOC	<del>1.64</del> <u>1.76</u> lbs/mmscf
PM10	<del>5.24</del> <u>5.57</u> lbs/mmscf
SOx (measured as SO <sub>2</sub> ):	<del>0.67</del> <u>0.71</u> lbs/mmscf

Compliance with the CO monthly limit shall be confirmed through the valid (per District Rule 218) CO CEMS or, absent valid CO CEMS, by the monthly fuel use data and the following emission factors:

<u>During Commissionin g</u>	<u>114.47</u>	<u>lbs/mmssc f</u>
<u>Following Commissionin g</u>	<u>13.10</u>	<u>lbs/mmssc f</u>

**Verification:** The project owner shall submit the monthly fuel use data and emission calculations to the CPM in the Quarterly Operation Reports (AQ-8).

AQ-13 reflected a District condition to maintain explicit control based on an outdated assumption made by the applicant so is no longer

**AQ-13** ~~Except for initial commissioning, the emissions shall not exceed the following limits: NO<sub>x</sub> (measured as NO<sub>2</sub>): 2 ppm at 15% oxygen from each gas turbine exhaust stack averaged over a year excluding periods of startup and shutdown as defined in Conditions AQ-10 and 235.9 tons per year total for all four turbines/HRSGs, including periods of startup and shutdown as defined in Conditions AQ-10.~~

~~**Verification:** The project owner shall submit all necessary data and emission calculations electronically to the CPM in the fourth Quarter Operation Report only (AQ-8) to verify compliance of the annual emission limits. The project owner shall submit to the CPM a copy of the annual RTC reconciliation report filed with the District within 10 days of the report's filing with the District.~~

This Condition has been modified to incorporate initial and on-going source test requirements. The District changed some of the source test methodology requirements and added explicit test location requirements.

**AQ-15** The project owner shall conduct an initial source test and annually thereafter for NO<sub>x</sub>, CO and NH<sub>3</sub> and once every three years thereafter for SO<sub>x</sub>, VOC and PM<sub>10</sub> of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the ~~Commission~~ CPM 45 days prior to the proposed ~~initial~~ source test date for approval. The protocol shall include the proposed operating

conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.

- ~~The source test shall be conducted within 60 days of the approval of the source test protocol by the District, but no later than 180 days following the date of first fire.~~
- The initial source test shall be conducted no later than 180 days following the date of first fire.
- ~~The District and Commission CPM~~ shall be notified at least ~~40~~ 7 days prior to the date and time of the source test.
- The initial source test shall be conducted with the gas turbine operating under loads of 50%, 75% and 100% of maximum.
- The initial source test shall be conducted to determine the oxygen levels in the exhaust.
- The initial source test shall measure the fuel flow rate, the flue gas flow rate and the as turbine generating output.
- The initial source test shall be conducted for the pollutants listed using the methods, and averaging times, and test locations indicated and as approved by the CPM:

Pollutant	Method	Averaging Time	<u>Test Location</u>
NOx	District Method 100.1	1 hour	<u>Outlet of SCR</u>
CO	District Method 100.1	<del>1 hour</del> <u>District Approved</u>	<u>Outlet of SCR</u>
SOx	<del>District Method 100.1</del> <u>District approved method</u>	<del>1 hour</del> <u>District Approved</u>	<u>Fuel Sample</u>
VOC	District approved method	1 hour	<u>Outlet of SCR</u>
PM10	District approved method	<del>1 hour</del> <u>District Approved</u>	<u>Outlet of SCR</u>
Ammonia	<del>District approved method</del> <u>District Methods 5.3 and 207.1 or EPA Method 17.</u>	1 hour	<u>Outlet of SCR</u>

- ~~The initial~~ source test results shall be submitted to the District and the ~~Commission CPM~~ no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
  1. ppmv corrected to 15% oxygen,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned and

4. additionally, for PM10 only, grains per dry standard cubic feet of fuel burned.

**Verification:** The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than ~~40~~ 7 days prior to the proposed initial source test date and time.

This condition describes the ammonia source testing requirements and shows the minor adjustments to reflect the District approach.

**AQ-16** The project owner shall conduct source testing of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the ~~Commission~~ CPM no later than ~~60~~ 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted quarterly for the first 12 months of operation and annually thereafter.
- NOx concentrations as determined by CEMS shall be simultaneously recorded during the ammonia test. If the NOx CEMS is inoperable, a test shall be conducted to determine the NOx emission by using District Method 100.1 measured over a 60 minute time period.
- Source testing shall be conducted to determine the ammonia emissions from each gas turbine exhaust stack using ~~an approved~~ District Method 5.3 and 207.1 or EPA Method 17 measured over a 1 hour averaging period.
- The District and ~~Commission~~ CPM shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the District and ~~Commission~~ CPM within 45 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The test shall be conducted when the equipment is operating at 80 percent load or greater.
- All emission data is to be expressed in the following units:
  1. ppmv corrected to 15% oxygen,
  2. pounds per hour,

3. pounds per million cubic feet of fuel burned and

**Verification:** The project owner shall submit the proposed protocol for the source tests ~~60~~ **45** days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 7 days prior to the proposed source test date and time. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.

**The following Conditions of Certification pertain to the following equipment:**

The applicant has requested that the Conditions of Certification revert back to include the original 5,900 bhp black start IC engine. This is reflected in the equipment description below:

~~Internal combustion engine, emergency power, diesel Caterpillar 3512B, electronically controlled, turbocharged, aftercooled, 2200 BHP A/N 366155 (ID. No. D54).~~

Internal combustion engine, emergency power, diesel Caterpillar 3612, 4° timing retard, turbocharged, aftercooled, 5900 BHP A/N 366155 (ID. No. D54).

This modification reflects the new CARB Ultra Low-Sulfur content diesel requirements at the District.

**AQ-18** The project owner shall not use fuel oil containing sulfur compounds in excess of ~~0.05 percent~~ 15 ppm by weight as supplied by the supplier.

**Verification:** The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Energy Commission (see AQ-21).

The applicant has requested that the Conditions of Certification revert back to include the original 5,900 bhp black start IC engine. This requires the reconstitution of previously deleted AQ-19.

**AQ-19 Deleted:** The project owner shall set and maintain the fuel injection timing of the emergency IC engine at 4° retarded relative to standard timing.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

The District has slightly modified the definition of “emergency” engines to include ~~that they operate LESS than 200 hours per year~~

**AQ-23** The project owner shall limit the operating time of the emergency IC engine to no more than ~~200~~ 199 hours per year.

**Verification:** The project owner shall submit the recorded data specified in condition AQ-21 on an annual basis as part of the fourth Quarter Operational Report (see AQ-8).

**The following Conditions of Certification pertain to the following equipment:**

This modification to the equipment description reflects the new firewater pump IC engine ~~that the applicant has petitioned~~

Internal combustion engine, emergency fire pump, diesel ~~Gummins-6BTA~~ Clarke Model JW6H-UF60, 4 9.7<sup>0</sup> timing retard, turbocharged, aftercooled, ~~182~~ 375 BHP A/N 366156 (ID. No. ~~D55-58~~).

This modification reflects the new CARB Ultra Low-Sulfur content diesel requirements at the District.

**AQ-24** The project owner shall not use fuel oil containing sulfur compounds in excess of ~~0.05 percent~~ 15 ppm by weight as supplied by the supplier.

**Verification:** The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Energy Commission (see AQ-27).

This modification to the equipment description reflects the new firewater pump IC engine ~~that the applicant has petitioned~~

**AQ-25** The project owner shall set and maintain the fuel injection timing of the fire pump IC engine at 4 9.7<sup>0</sup> retarded relative to standard timing.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.

The District has slightly modified the definition of “emergency” engines to include ~~that they operate LESS than 200 hours per year~~

**AQ-28** The project owner shall limit the operating time of the fire pump IC engine to no more than ~~200~~ 199 hours per year.

**Verification:** The project owner shall submit the recorded data specified in condition AQ-27 on an annual basis as part of the fourth Quarter Operational Report (see AQ-8).

These modifications reflect the new BACT finding for NO<sub>x</sub>, the new emissions for startup, cold-startup and combustor-tuning.

**AQ-36** The gas turbines shall not be operated unless the operator demonstrates to the District and CPM that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, the gas turbines shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

The owner/operator shall limit the first year, defined as the first 12 months following initial operation, cumulative facility wide NO<sub>x</sub> emissions from all equipment to no more than 492,897 lbs/year.

The owner/operator shall, prior to the beginning of all years subsequent to the first year (as defined above), hold a minimum of 464,338 lbs of NO<sub>x</sub> RTCs for the operation of all equipment at the facility.

In accordance with District Rule 2005 (f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year.

**Verification:** The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District in each Quarterly Operational Report. (see AQ-8).

**The following Conditions of Certification pertain to the following equipment:**

This reflects the applicant requested changes to the ammonia storage facilities. They are proposing to eliminate two storage tanks and increase the size of the remaining ~~one~~

~~Storage tank, TK-1, serving SCRs 3-1 and 3-2 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366162 (ID No. D56).~~

~~Storage tank, TK-2, serving SCRs 4-3 and 4-4 with a vapor return line, aqueous ammonia 24.5% solution, 22,500 gallons A/N 366163 (ID No. D57).~~

Storage tank, TK-3, aqueous ammonia, 24.5% wt., serving SCRs 3-1, 3-2, 4-3, 4-4, with a vapor return line, ~~22,500~~ 36,000 gallons (ID No. D60)

This modification is a minor clarification from the District.
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**AQ-38** The project owner shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig in the aqueous ammonia storage tank.

**Verification:** The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Energy Commission.